Decision 02-07-035 July 17, 2002

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking into the operation of interruptible load programs offered by Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company and the effect of these programs on energy prices, other demand responsiveness programs, and the reliability of the electric system.	Rulemaking 00-10-002 (Filed October 5, 2000) Phase 2

INTERIM OPINION ON DEMAND BIDDING PROGRAM

1. Summary

We authorize limited changes to the demand bidding program (DBP). The changes transition DBP to a reliability program, and increase the feasibility of its operation for Summer 2002.

As revised, requests and bids are not limited to three blocks of four hours each, but may be for any hours of identified need. The program may be operated on a day-ahead or day-of basis. The price is fixed at $0.35/per kilowatt-hour (kWh). Utilities will solicit customer bids, accept or reject each bid, and pay participants based on performance. DBP expenses may be tracked in the memorandum account for total program expenses. The annual program total cost cap for Southern California Edison Company (SCE) is raised by $10 million.

Each utility shall file an advice letter within five days of the date of this order to implement these changes. The changes will be effective in five days unless suspended by the Energy Division Director. This proceeding remains open to address two petitions for modification.

2. Background

In our decision on Phase 2 matters, we kept this proceeding open for further consideration of the DBP. (Decision (D.) 02-04-060, Ordering Paragraph 21.) In particular, we said:

> "…we keep this proceeding open to examine the future of the DBP. DWR [Department of Water Resources] may or may not be able to fund the DBP for Summer 2002. We want continuation of this program, or a smooth transition to a similar program, because this or a similar program provides unique flexibility for customer participation and payment based on performance. Customers are familiar with DBP, and both hardware and software are in place for its implementation. The Assigned Commissioner and Administrative Law Judge should seek comment on alternatives as appropriate for our further consideration and resolution before this summer."
> (D.02-04-060, mimeo., page 54.)

Comments on the future of DBP and alternatives were sought by Ruling dated May 14, 2002. On May 20, 2002, comments were filed and served by Pacific Gas and Electric Company (PG&E), SCE, San Diego Gas and Electric Company (SDG&E) and the Office of Ratepayer Advocates (ORA). On May 24, 2002, reply comments were filed and served by PG&E, SCE and ORA.

Utilities largely recommend against wholesale redesign of DBP and suggest several limited changes. Utilities state that they are not procuring electricity, and do not have access to the information necessary to determine when to activate the program or how much load relief to request. SCE recommends a single DBP price rather than the current range of four prices in two tiers. Utilities generally oppose revival of the Voluntary Demand Response Program (VDRP) or other alternatives to DBP.

ORA recommends resurrecting the California Independent System Operator (ISO) Discretionary Load Curtailment Program (DLCP) and linking DLCP with the Optional Binding Mandatory Curtailment (OBMC) program. ORA suggests adding an initial DBP price at the Federal Energy Regulatory Commission (FERC) current wholesale spot market price cap of $0.09187/kWh.

3. Demand Bidding Program

We make limited changes to the DBP. The revised program is contained in Attachment A.

We agree with utilities that relatively minor modifications to DBP are preferable to a wholesale redesign of DBP, reactivation of VDRP, or development and adoption of a new program (such as linking OBMC with DLCP). DBP is essentially up and running. Customers have signed DBP agreements, are familiar with the basics of the program, and are prepared to make load curtailment bids immediately. One or more websites are in place for DBP implementation.

On the other hand, major changes to DBP, reactivation of VDRP, or development of a new program would require relatively more customer education, and may engender customer resistance (e.g., if customers view changes as providing inadequate additional value for the corresponding inconvenience or burden). Further, significant program changes would require enrollments in the revised or new program, may involve additional expenses for system modifications, and would necessitate time for implementation that is unavailable given the arrival of Summer 2002.

3.1. Time Blocks; Program Initiation; and Use During Stages 1, 2, and 3

The original DBP employed three four-hour time blocks for bids and operation. This was in part a balance between program simplicity (e.g., known, limited parameters) and complexity (e.g., infinite possibilities to allow more precise matching of supply and demand). It is now reasonable to remove the limit of three four-hour time blocks. ISO and utilities should be permitted to seek load relief in any combination of hours that will best match supply and demand. ISO and utilities may continue to employ three four-hour time blocks if that reflects their best judgment regarding use of the program. While we do not go as far in program redesign as recommended by ORA, this modest change, to be implemented at ISO's and utilities' discretion, provides a reasonable increase in flexibility to potentially better match supply and demand for Summer 2002.

We agree with utilities that they are not in a position to determine when DBP should be called. We adopt SCE's recommendation that DBP events should be activated by the ISO. This is consistent with our transitioning DBP to a reliability program, as discussed more below, given ISO's role in monitoring operating reserves.[1] To promote clarity, the revised DBP will specifically state that ISO will notify utilities when additional load relief is needed.

---

[1] The ISO is responsible for monitoring the state's generation operating reserve, and notifying market participants and state agencies when an emergency is likely, or is called. The ISO declares a Stage 1 emergency when forecast or actual operating reserves are less than 7% of available capacity. A Stage 2 emergency is declared when forecast or actual operating reserves are less than 5% of available capacity. A Stage 3 emergency is declared when forecast or actual operating reserves are less than 1.5% of available capacity. The ISO may call for rotating outages during Stage 3 emergencies.

We accept the recommendations of ISO and utilities that DBP is best triggered by an ISO Alert Notice. According to ISO, a 24-hour Alert Notice is issued if “there is a potential for firm load curtailment within the next 24 hours based on forecasted load and resources.” (ISO Procedure E-508, page 3, Exhibit A to June 21, 2002 ISO Comments.) ISO recommends that the DBP timetable be modified to permit more flexibility, however, since alerts might be issued after 2 p.m. the day before.

We agree that more flexibility is needed. In particular, we adopt use of an ISO Alert Notice to trigger DBP, but do not limit the solicitation of bids to the afternoon of the day before. Rather, bids may be solicited on shorter timeframes if real time operations by ISO do not permit more notice to utilities and customers. We generally adopt a one-hour timeframe for utilities to solicit bids, one-hour for customers to submit bids, and one-hour for utilities to evaluate bids and notify customers of the results. We do not require automatic rejection of bids that might be submitted after the one-hour deadline to submit bids, but utilities are not obligated to evaluate late bids equally with timely bids, and should take current conditions into account in evaluating late bids.

DBP was originally focused on Stage 2 and 3 events. (See, for example, Executive Order D-39-01 dated June 9, 2001, revised June 11, 2001, first ordering paragraph; also D.01-07-025, mimeo., page 1.) As revised, we do not limit focus to only Stage 2 and 3. Rather, we adopt the joint recommendation of PG&E, SCE, SDG&E and ISO to employ DBP as an “emergency avoidance program” (not just an “emergency response program”) within a comprehensive portfolio of load management programs to support system reliability. (Joint Comments July 9, 2002, page 2.)

In this role, DBP is a reliability-focused load reduction program that may provide sufficient load relief to eliminate the need for load curtailments. The required lead time of 3 hours or more before customers may implement bid results means its value is moved further toward the beginning of the process—that is, to deliver load relief to reduce the potential for voluntary (Stage 2) or involuntary (Stage 3) load curtailments. We agree with utilities and ISO that implementing DBP prior to Stages 2 and 3 does not undermine its effectiveness as a reliability program or convert it to a price mitigation program.

At the same time, however, we do not want early implementation of DBP to result in a program that is used unwisely at excessive cost. Utilities and ISO state that this is unlikely since customers are paid for performance (so payments will be consistent with actual load relief delivered to the system), and current experience and load reduction commitments do not suggest that participation levels will generate excessive cost. Utilities report, for example, past experience showing not all customers will participate in any particular event, and even those who participate may not deliver the full amount of load relief that was bid. Utilities state that they keep the Commission informed on performance and cost through monthly reports, and if load relief and cost significantly increase and/or begin to approach the annual cap, "utilities can alert the Commission so that the issue can be addressed…" (Joint Comments, July 9, 2002, page 4.)

Our concern can be largely addressed by timely notification. We consider but reject adopting weekly (or other additional) reporting requirements to monitor DBP performance and cost. In exchange for not imposing an additional reporting burden on all three utilities, however, we expect each utility to notify the Commission and parties promptly if DBP load relief and/or cost begin to significantly increase on a utility's system as a result of today's modifications.

Notification must be as soon as the utility detects concerns that should be brought to our attention, and the utility must not wait until the next routine monthly report. Notification should be followed-up quickly by a petition for modification if the utility or a party recommends any changes in DBP.

3.2. Transition to Reliability Program

We agree with utilities that a modified DBP can fill a niche for a voluntary, non-penalty-based, day-ahead, reliability program. DBP initially served many goals. One goal was as a price responsive program that could potentially mitigate against high wholesale prices. As SCE points out, however, DBP has not operated as originally intended because the market has not exhibited the price volatility that makes a price response / mitigation program necessary and desirable. Nonetheless, DBP can still deliver value in a portfolio of load management programs by transitioning to a reliability program.

In making this transition to a reliability program, we also seek alternative funding and a utility role consistent with that funding. We continue utility monitoring of DBP curtailments as provided in the current program, but add utility evaluation of bids and payment to DBP participants based on performance. Utility funding will provide resources to promote program use, while utility evaluation of bids will increase the utility's role. Each utility may record DBP payments in its interruptible program memorandum account for subsequent recovery. We modify the pricing structure to provide necessary feasibility for utility evaluation of bids.

We agree with SCE that a single incentive level will promote transforming DBP into a reliability program. A range of prices focuses the program on price response and price mitigation, while a single price promotes using the program for system reliability. A range of DBP bids at different prices also requires bid evaluation at each price in relation to all other options at each price. DWR has information on all resources, but, as utilities point out, utilities currently do not have access to sufficient information to make that judgment regarding all possible options.

Therefore, we adopt SCE's recommendation to employ a single price. We set that price at $0.35/kWh, the same level we adopted for the VDRP. (D.01-04-006, mimeo., page 31.) As with the VDRP price, this balances a range of possible prices addressed by parties, from the low end (the level of the current FERC wholesale spot market price cap ($0.09187/kWh) recommended by ORA) to the high end (prices and penalties for mandatory curtailment programs).[2] It reflects the voluntary nature of the program, the benefit of advance notice provided by this program compared to other programs, the absence of penalties, and a price level below that of existing mandatory curtailment programs.

Moreover, a single price at a reasonable level removes the opportunity for participants to manipulate the system to their advantage (e.g., by participants limiting offers to only those at the highest price). A single price at a reasonable level balances competing interests and promotes efficiency. Parties may use the expedited methods discussed in our Phase 1 order to seek adjustment of the price, if necessary. (D.01-04-006, mimeo., pages 31-32.)

Utilities should use first-come first-served as a primary criterion for accepting a bid, taking past non-performance or non-compliance by the customer

---

[2] As ORA observes, paying more than $0.092/kWh is moot if supply-side resources are available at the price cap or less. On the other hand, if the cap results in a shortage, it is reasonable to pay customers more to use less (which ORA analogizes to the 20/20 conservation program).

into account. We adopt utilities' proposal for implementing a fair mechanism for non-performance and non-compliance measurement based on preliminary meter data for a series of consecutive events.

We also adopt utilities' recommendation to limit customer bids to one per day in consecutive hours, with a minimum duration of 2 hours. A multitude of disjointed bids from a single customer would otherwise unreasonably complicate the program.

Further, we agree with utilities that accepted bids should not subsequently be cancelled. Customers with accepted DBP bids commit to a demand curtailment. They should be compensated for that commitment based on their actual performance regardless of whether the ISO later cancels the Alert Notice.

Finally, we agree with utilities that customers should not be permitted to simultaneously participate in multiple programs with the potential of being paid twice for a single event. Thus, just as we preclude DBP customers from participating in the ISO's Demand Relief Program and Ancillary Services Load Program, we similarly preclude their participation in the California Power Authority's new Demand Reserves Program.

3.3. Interruptible Program Cap

SCE proposes that DBP incentive payments not be included in the interruptible and curtailment program total funding cap. SCE argues that the Commission did not consider these payments when the cost cap was set, and that SCE projects it will be close to, or exceed, the cap before the conclusion of Summer 2002. SCE asserts that if DBP is called on frequently this summer, SCE could be forced to suspend all interruptible program activities during a time of critical need as the cost cap is reached.

We decline to adopt SCE's proposal. SCE's proposal is effectively an "infinite" cost cap for one program. This could have the undesirable effect of encouraging use of one program over others unrelated to the merits or individual costs of each program. Further, the cost cap is a "method to apply some guidance and control to these programs without adopting unreasonable expectations or constraints." (D.02-04-060, mimeo., page 21, footnote 9.) The cap prevents "these programs from spiraling out of control if conditions unexpectedly and dramatically change…" (D.02-04-060., mimeo., pages 20-21.)

VDRP was included in the original cost cap. (D.01-04-006.) VDRP was replaced by DBP, but the cost cap was not reduced to reflect DWR funding of DBP. (D.01-07-025.). The cost cap was subsequently reduced for all utilities consistent with a revised overall program goal of 2,500 MW. (D.02-04-060.) PG&E and SDG&E do not argue that there was a failure to consider DBP in the original or revised cost cap. SCE does not convincingly show that there was such failure.

Nonetheless, SCE is concerned that it may approach its annual cost cap of $137.5 million.[3] To address this limited concern, we raise SCE's cost cap by

---

[3] SCE's monthly reports through May 21, 2002 include estimates of total expenses for 2002 and the total program cost cap. In three out of the last four months through May 21, 2002 the estimates have been in the range of $120 million. For example, SCE's monthly report dated February 7, 2002 estimates total expenses for 2002 of $120.0 million with the original total program cost cap of $275.0 million. SCE's monthly report dated March 7, 2002 estimates 2002 expenses of $121.7 million with a cost cap of $275.0 million. SCE's monthly report dated April 8, 2002 estimates 2002 expenses of $133.8 million with a reduced cost cap of $137.5 million. (The cost cap was reduced in D.02-04-060.) SCE's monthly report dated May 21, 2002 estimates 2002 expenses of $119.3 million with a cost cap of $137.5 million. (SCE's monthly reported dated June 21, 2002 does not contain an estimate for 2002, but reports expenditures of about $46.6

Footnote continued on next page

$10 million, to a total of $147.5 million. This increase will fund approximately 47 MW of DBP resources for 10 hours per day for 60 non-holiday weekdays.[4] This is a reasonable amount for Summer 2002 without being excessive.

We remind parties "that any party may file a timely pleading if, in the party's judgment, program limits should be adjusted upward or downward (e.g., a utility may file an application; a utility or party may file a petition for modification)." (D.02-04-060, mimeo., page 21.) We adopted a requirement for the filing of monthly reports by utilities to help utilities, parties and the Commission monitor whether cost caps are being approached, and we allowed for acting on an emergency basis to increase megawatt or dollar limits if necessary. (D.01-04-060, mimeo., page 80.)

Under no circumstances should a utility be forced to suspend all interruptible program activities based on its reaching the cost cap. Rather, a utility must file a timely pleading seeking a further increase if it forecasts that it may reach the cost cap. The utility should file that pleading with adequate time for parties to comment and the Commission to act in the normal course of Commission business. If necessary, however, the Commission will act on an emergency basis. Any utility's failure to follow this procedure in a timely way,

---

million through May 31, 2002; if expenditures for June through December average $11 million per month, the 2002 annual total would be about $123.6 million.)

[4] 47 MW for 10 hours per day for 60 non-holiday weekdays (12 weeks) is 28,200 megawatt-hours. At a payment of $0.35 / kWh, the total cost would be $9.87 million. SCE currently has 96 customers representing 133 service accounts subscribed to DBP. The aggregate maximum demand of these participants is 211 MW. The minimum potential load reduction for these customers, under the terms of the DBP tariff, is 16 MW.

resulting in the utility suspending interruptible programs during a system emergency and thereby jeopardizing the health, safety and welfare of the state's citizens, would be unreasonable absent a very compelling reason to the contrary.

SCE does not request an increase in its interruptible program limit of 1,375 MW. No party comments on any necessary change in the capacity limit. We do not adopt an adjustment in SCE's total interruptible program megawatt limit.

3.4. Cost Recovery

SCE also recommends that the Commission make an explicit finding that all incentive dollars paid by utilities are *per se* reasonable upon verification of the customer's actual load reduction. This would be reasonable, according to SCE, since ISO triggers program activation and event scope rather than the utility. We decline to make this finding. Rather, we expect utilities in the revised DBP to take more than a purely passive role in DBP operation.

Moreover, we have already provided that reasonable implementation costs not otherwise recovered through existing rates, or offset by revenues, are subject to later recovery. As we said in both the Phase 1 and Phase 2 orders, during this continuing State of Emergency in the California electricity market:

> "We will review the balance in each memorandum account for reasonableness before authorizing recovery but, absent incompetence, malfeasance, or other unreasonableness, we would expect to authorize full recovery of all dollars spent by the utilities for these programs to get California through this crisis." (D.01-04-006, mimeo., page 78; also see D.02-04-060, mimeo., page 21.)

Utilities need no additional assurance of recovery at this time.

4. Need for Expedited Consideration

Rule 77.7(f)(9) of the Commission's Rules of Practice and Procedure provides in relevant part that:

> "…the Commission may reduce or waive the period for public review and comment under this rule…for a decision where the Commission determines, on the motion of a party or on its own motion, that public necessity requires reduction or waiver of the 30-day period for public review and comment. For purposes of this subsection, "public necessity" refers to circumstances in which the public interest in the Commission adopting a decision before expiration of the 30-day review and comment period clearly outweighs the public interest in having the full 30-day period for review and comment. "Public necessity" includes, without limitation, circumstances where failure to adopt a decision before expiration of the 30-day review and comment period…would cause significant harm to public health or welfare. When acting pursuant to this subsection, the Commission will provide such reduced period for public review and comment as is consistent with the public necessity requiring reduction or waiver."

We balance the public interest in quickly modifying the DBP against the public interest in having a full 30-day comment cycle on the proposed modification. We conclude that the former outweighs the latter. The DBP will protect public health, safety and welfare in Summer 2002 by promoting system reliability. Any delay in implementing a revised DBP jeopardizes public health, safety and welfare by increasing the risk of customers experiencing a less reliable system, including the potential of rotating outages. We seek valuable public review of, and comment on, the proposed change, and find that a reduced period balances the need for that input with the need for timely action.

5. Comments on Draft Decision

On June 18, 2002, the draft decision of Presiding Officer and Assigned Commissioner Wood on this matter was filed and served on parties in accordance with Section 311(g)(1) of the Public Utilities Code and Rule 77.7 of the Rules of Practice and Procedure. Comments were filed and served on June 21, 2002 by ISO and jointly by PG&E, SCE and SDG&E. Reply comments were filed and served on June 25, 2002 by ISO and jointly by PG&E, SCE and SDG&E. We incorporated changes based on comments and reply comments. In particular, we incorporated day-of features in the program, included joint utilities' recommendations regarding nonperformance measurement, limited submission of bids to one per day, declined simultaneous participation in the California Power Authority's Demand Reserves Program, and provided five days for utilities to file and serve advice letters with tariffs in compliance with this order.

On July 2, 2002, the revised draft decision of Presiding Officer and Assigned Commissioner Carl Wood on this matter was filed and served on parties. Comments were filed and served on July 9, 2002 jointly by PG&E, SCE, SDG&E and ISO. No reply comments were filed. We incorporate changes recommended in the joint comments. In particular, we do not limit program focus to Stage 2 and 3 emergencies, and permit utilities to accept all bids unless the ISO specifies a capacity limit.

Findings of Fact

1. Relatively minor changes to DBP are preferable to a wholesale redesign of DBP, reactivation of VDRP, or development and adoption of a new program since DBP is up and running, agreements are in place, customers are familiar with DBP, and customers are prepared to make load curtailment bids

immediately while, in contrast, major changes or a new program would require education, may face resistance, would require new enrollments, may involve new costs, and would require time that is unavailable.

2. Utilities are not in a position to determine when DBP should be called.

3. Flexibility to balance supply and demand is increased by (a) removing the limitation that ISO and utilities must employ three four-hour time blocks for DBP, and (b) allowing implementation on a day-of as well as day-ahead basis.

4. DBP has not operated as a price response/mitigation program because the market has not exhibited substantial price volatility since DBP was adopted.

5. A modified DBP can fill a niche for a voluntary, non-penalty-based, day-ahead, reliability program.

6. A single incentive level promotes transforming DBP to a reliability program.

7. Utility funding will provide resources to promote feasible program use, while utility evaluation of bids will increase the utility's role consistent with utility funding and transition of DBP to a reliability program.

8. A single DBP price at $0.35/kWh balances a range of possible prices, reflects several factors (e.g., the voluntary nature of the program, the benefit of advance notice, the absence of penalties, and a price level below that of existing mandatory curtailment programs), and removes the opportunity for participants to manipulate the system to their advantage.

9. DBP customers should not be permitted to simultaneously participate in multiple programs with the potential for being paid twice for a single event, such as ISO's Demand Relief Program, ISO's Ancillary Services Load Program, and California Power Authority's new Demand Reserves Program.

10 SCE is concerned that it may approach its annual cost cap of $137.5 million.

11. A cost cap increase of $10 million for SCE will fund about 47 MW of DBP load relief for 10 hours per day for 60 non-holiday weekdays.

12. Any utility's failure to follow adopted procedures to increase the interruptible program cost cap in a timely way, resulting in the utility suspending interruptible programs during a system emergency and thereby jeopardizing the health, safety and welfare of the state's citizens, is unreasonable absent the utility presenting a very compelling reason to the contrary.

13. Utilities need no further assurance of cost recovery at this time.

14. The public interest in quickly modifying the DBP outweighs the public interest in having a full 30-day comment cycle on the draft decision.

Conclusions of Law

1. The DBP should be revised to permit ISO to employ DBP as needed in other than three four-hour time blocks on either a day-ahead or day-of basis.

2. DBP should be transitioned to an emergency avoidance reliability program at a single incentive payment level of $0.35 / kWh.

3. The DBP stated in Attachment A should be adopted.

4. A utility should notify the Commission and parties promptly if demand bidding program load relief or cost begin to significantly increase on a utility's system as a result of the modifications adopted in this order, and should quickly file a petition for modification if the utility recommends any changes in the demand bidding program.

5. DBP should be funded by utilities and DBP expenses should be allowed to be recorded in each utility's interruptible program memorandum account.

6. Each utility should evaluate DBP bids within its service area and accept bids from reliable customers (taking past performance into account) on a first-come first-served basis.

7. SCE's interruptible and curtailment program cost cap (D.02-04-060, Ordering Paragraph 19) should be increased by $10 million, to a total of $147.5 million.

8. The period for public review and comment on the draft decision should be reduced.

9. This proceeding should remain open.

10. This order should be effective today so that the revised DBP may be implemented without delay to protect public health, safety and welfare.

INTERIM ORDER ON DEMAND BIDDING PROGRAM

IT IS ORDERED that:

1. Within five days of the date of this order, respondent utilities Pacific Gas & Electric Company, Southern California Edison Company (SCE), and San Diego Gas & Electric Company shall each file and serve an advice letter with revised tariffs. Each advice letter with revised tariffs shall implement revisions to the demand bidding program described in this order and in Attachment A. Each advice letter with tariffs shall be in compliance with General Order 96-A. Each advice letter with tariffs shall become effective five days after filing, unless suspended by the Energy Division Director. If any advice letter with accompanying tariffs is suspended by the Energy Division Director, the advice letter and tariffs shall become effective upon the date the Energy Division

Director determines that the tariffs comply with this order. The Energy Division Director may require a respondent utility to amend its advice letter and tariffs to comply with the orders herein. Respondent utilities shall work with the Energy Division Director and staff to prepare advice letters and tariffs that are consistent with the orders herein, and reasonably consistent among utilities.

2. A respondent utility shall notify the Commission and parties promptly if demand bidding program load relief or cost begin to significantly increase on a utility's system as a result of the modifications adopted in this order, and shall quickly file a petition for modification if the utility recommends any changes in the demand bidding program.

3. The total annual program dollar limit for SCE (Decision (D.) 02-04-060, Ordering Paragraph 19) is increased by $10 million to a total of $147.5 million.

4. This proceeding remains open solely to address the February 20, 2002 petition for modification of D.01-09-020 filed by Dr. Lee F. Walker and the

May 22, 2002 petition for modification of D.02-04-060 filed by California Industrial Users and California Large Energy Consumers Association.

This order is effective today.

Dated July 17, 2002, at San Francisco, California.

LORETTA M. LYNCH
President
HENRY M. DUQUE
CARL W. WOOD
GEOFFREY F. BROWN
MICHAEL R. PEEVEY
Commissioners

ATTACHMENT A
DEMAND BIDDING PROGRAM

The Demand Bidding Program (DBP; see Decision 01-07-025; Attachment A) is replaced with the following program:

2.6 Demand Bidding Program (Revision 1.0)

2.6.1 The Offer

2.6.1.1 The California Independent System Operator (ISO) shall notify each utility distribution company (UDC) when demand bidding program (DBP) load relief may be needed in the day-ahead and day-of markets to mitigate shortages in operating reserves that have the potential to lead to Stage 2 or 3 Emergency events. Unless a capacity level (megawatt quantity) is specified in the ISO notification, the UDCs will deem all bids acceptable from customers. In the event the ISO specifies a limited capacity in its notification, the UDCs will accept bids on a first-come, first-served basis up to the ISO's specified amount. Unless the ISO identifies a specific time period, the bid event shall be deemed to occur between 12:00 p.m. and 8:00 p.m. for the day-ahead program and between 3:00 p.m. and 8:00 p.m. for the day-of program.

2.6.1.2 The triggering event in the day-ahead market may be an ISO 24-hour Alert Notice, which is the first indication that there potentially will be less than 7% operating reserves within the next 24 hours. UDCs will trigger a day-ahead event based on receipt of this Alert Notice or more advanced ISO Notice (Warning or Stage 1, 2, or 3 Emergency) issued by the ISO by 2 p.m. on the day preceding the event.

2.6.1.3 The triggering event in the day-of market may be an ISO 24-hour Alert Notice or an ISO hour-ahead Warning Notice. The Warning Notice is the first indication that there potentially will be less than 7% operating reserves within the next hour. UDCs will trigger a day-of event based on an Alert or Warning Notice or more advanced ISO Notice (Stage 1, 2, or 3 Emergency) issued by the ISO after 2 p.m. on the day preceding the event and up to

11:00 a.m. on the day of the event.

2.6.1.4 For the day-ahead program, participating customers shall submit bids to a DBP website within one hour of notification of bid solicitation, but not later than 4:00 p.m. on the day preceding the curtailment event. For the day-of program, participating customers shall submit bids to the DBP website within one hour of receipt of notification of bid solicitation, but not later than 2:00 p.m. on the day of the curtailment event. UDCs may also notify customers via the internet and other means of communication as needed of DBP events on a day-ahead and day-of basis.

2.6.1.5 A customer bid may be submitted beyond one hour after notification of bid solicitation, but the utility need not give equal consideration to late and timely bids. In evaluating late bids, the utility must consider then current conditions, including previous acceptance or rejection of timely bids submitted within the first hour. Bidding shall be accepted for non-holiday weekdays only.

2.6.1.6 Participants shall indicate the amount of kilowatt (kW) curtailment they are offering by hour for each DBP event. For each event, customer bids must consist of a single period of consecutive hours of curtailment, with a minimum duration of two hours. Customers may submit no more than one bid for a particular day of requested load curtailment. Once a customer's bid has been accepted in the day-ahead program, the customer may not submit a curtailment bid in the day-of program for the same day of requested load curtailment.

2.6.1.7 DBP load reductions shall be paid at the rate of 35 cents ($0.35) per kilowatt-hour for both the day-ahead and day-of programs.

2.6.2 DBP Offer Evaluation and Confirmation

2.6.2.1 Within one hour after the bid submission deadline but not later than 5:00 p.m. for a day-ahead event and not later than 2:00 p.m. for a day-of event, each UDC shall evaluate each bid timely submitted within its service area, accept or reject each bid, and notify each bidder of the result. Bid solicitations can be terminated up to this point, based on ISO notification that load relief is no longer needed.

2.6.2.2. In the event a bid is limited (by quantity) by the ISO, the primary criterion for accepting bids shall be reliable offers (taking bidder past performance and compliance into account) on a first-come first-served basis. If preliminary meter data indicates that a customer is not entitled to receive compensation for three consecutive events, such customer should thereafter be precluded from participating in the following two operations of the DBP.

2.6.3 DBP Performance Verification and Payment

2.6.3.1. The UDC will track the curtailment of participating customers. The UDC will review the performance meter data against the accepted bids and calculate the payment due to the participating customers, with payments based on actual performance.

2.6.3.2 Each UDC shall pay the incentive amounts due to individual participants within 90 days of the DBP curtailment event.

2.6.3.3. Program expenses may be tracked in the memorandum account authorized to track interruptible program expenses. (Decision (D.) 01-04-006, Ordering Paragraphs (OPs) 15 and 16; D.01-07-029, OPs 2 and 3; D.02-04-060, OP 19.)

2.6.3.4. Participants will only be paid for a maximum of 150 percent of their accepted bid kW load drop measured on an hourly basis. Participants must drop at least 50 percent of their bid load drop to qualify for any payment in any hour. In no case will a customer be paid an incentive if load drop does not meet 10% of the customer's average annual demand but not less than 100 kW.

2.6.3.5 Baseline load for measuring load drop will be computed pursuant to the “10-day rolling average” methodology or baseline methodology pursuant to each UDC’s currently approved DBP tariff.

2.6.3.6 Once a customer bid has been accepted, the accepted bid shall not subsequently be rejected by the utility, but payment shall continue to be based on the customer's actual performance.

2.6.4. Participation Requirements

To participate in the program, customers must meet the following minimum requirements:

2.6.4.1. Individual bids should be a minimum of 10 percent of each customer account's average annual demand, but not less than 100 kW per customer account. No aggregation of customer accounts will be allowed.

2.6.4.2. Customers must have an interval meter. For customers over 200 kW the meter will be provided pursuant to the California Energy Commission's real time electric meter (RTEM) program, based on available funding. For customers under 200 kW the meter will be provided at no charge to the customer and meter expenses will be recorded in a memorandum account for future rate recovery. Customers who receive meters at "no charge" will be obligated to perform or qualify to receive compensation during the first 10 events, if bids are requested and the customer's bid is accepted, and remain on the program for one year.

2.6.4.3. DBP customers may not also be enrolled in the ISO's Demand Relief Program, the Participating Load Program, also known as the Ancillary Services Load Program, or the California Power Authority Demand Reserves Program. Customers may achieve load drop by operating back-up or onsite generation. The customer will be solely responsible for meeting all environmental and other regulatory requirements for the operation of such generation.

(END OF ATTACHMENT A)